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THE JOURNAL OF RESOURCE RECOVERY

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86 Comment
Dr. James G. Abert
NCRR President

87 NCRR Project Reports — 1972 to 1981

89 Landfill Methane Utilization
Technology for extracting and using methane-containing gas from landfills is developing rapidly, spurred by federal regulations and energy costs. This overview looks at incentives, typical recovery systems and the end uses of gas recovered from landfills.

92 Waste for Space: Recovering Energy in Hampton, Va.
Since November 1980, a 200-ton-per-day facility in Hampton, Va., has burned municipal refuse from the city and government installations, producing steam used by NASA's Langley Research Center. The process and the unique city/federal cooperation are described.

97 Composting as a Recovery Option
Composting is "alive and well as a waste treatment method," according to this article. Methods of composting are discussed and several composting projects, both for sewage sludge and solid waste, are profiled.

101 Municipal Solid Waste: A Utility Fuel?
This article, written specially for the ***NCRR Bulletin*** *by C.R. McGowin of the Electric Power Research Institute, Palo Alto, Calif., examines the advantages and disadvantages of burning waste fuels.*

109 Waste Fuel Storage, Metering, Transport and Feed Systems
A brief description of waste fuel handling systems, with a review of 10 selected fuel-burning operations.

Landfill Methane Utilization

By RUSSELL C. EBERHART
and
LINDA GREEN PHILLIPS

Landfill methane recovery and utilization consists of obtaining gas from a sanitary landfill for use as an energy resource. Many factors enter into the feasibility of a gas recovery system at a landfill. The age, size, moisture, average depth, tons in place and potential end use of the gas are key factors.

Economical gas recovery for commercial utilization typically requires a landfill at least 30 to 40 feet deep, on the average. For economical methane production, it is desirable to have roughly one or two million tons of refuse in place. A decision to collect and process the gas should be based on site-specific findings made with the assistance of a competent engineering firm with experience in landfill methane recovery and utilization systems.

It is now believed that between 1000 and 10,000 landfills in the United States are eligible for profitable gas recovery and utilization. Current estimates are that about 200 billion cubic feet of methane could be produced from these landfills each year, resulting in a $400-to-$500 million per year industry. Ten utilization systems are currently on-line in the U.S., with several scheduled for start-up within the next few months.

Recovery Incentives

Incentives to initiate gas recovery generally fall into one or more of the following areas: the prediction of a high economic rate of return on investment, the need to comply with legal requirements, and the desire to realize certain social and environmental benefits. Although one of the three areas is generally dominant at any particular site, elements of all three are almost always present.

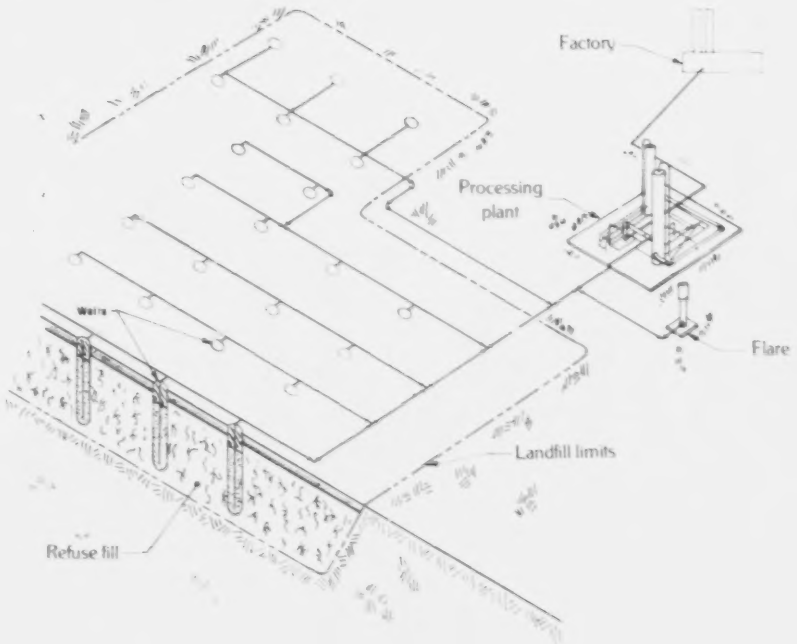
The key to many successful landfill gas projects is the financial packaging. Given the relatively high levels of interest rates which now exist, a return on investment of around 25 percent is often required to make a gas recovery project attractive to private investors. A public (or nonprofit) entity has certain inherent advantages, particularly when it owns the landfill and the gas rights. Among the advantages are: (1) no royalty payments are required to purchase and use the gas; (2) capital tax credits and pollution tax credits may be passed through to a money lender; and (3) funds may be raised by the issuance of tax-free money instruments.

Banks, equipment suppliers, leasing companies and private entrepreneurs are interested in providing funding for the capital cost items. It is possible in certain projects for the public sector participant to see the project development proceed with no financial obligation on its part. The public entity derives a revenue stream from the gas sales, but it merely offsets other operation expenses, as it is a nonprofit organization.

Recently, several major banks and private party groups have indicated a willingness to participate in landfill gas recovery projects. Further, a willingness to participate in selected financial packages has been voiced by a few of the larger utility companies and at least one equipment manufacturer.

Capital costs of systems currently in operation have ranged from $400,000 to $10 million. Typically, the expected cost of the energy obtained from a medium-

Figure 1
Typical Landfill Methane Recovery System



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Landfill Methane

Table I
Summary of Systems Currently On-Line

Landfill	Location	Developer(s)	Landfill Gas Recovered (MMcfd)	Quality of Gas Sold (Btu/scf)
Palos Verdes	Rolling Hills Estates, CA	Getty Synthetic Fuels, Inc.	1.8	1,000
Mountain View	Mountain View, CA	Pacific Gas & Electric Co.	0.7	700
Azusa	Azusa, CA	Azusa Land Reclamation Co.	0.5	500
Ascon	Wilmington, CA	Watson Energy Systems, Inc.	1.5	530
Operating Industries	Monterey Park, CA	Getty Synthetic Fuels, Inc.	8.0	1,000
Cinnaminson	Cinnaminson, NJ	Public Service Electric and Gas Co.	0.8	600
Sheldon Arleta	Los Angeles, CA	City of Los Angeles	1.4	500
City of Industry	Industry Hills, CA	SCS Engineers, Inc., and City of Industry	0.6	500
Bradley East	Los Angeles, CA	Genstar Gas Recovery Systems, Inc., and Conrock Co.	2.0	500
C.I.D.	Calumet City, IL	Getty Synthetic Fuels, Inc.	5.0	1,000

Btu system is $1.70-$2.00 per million Btu (MMBtu); for systems that upgrade the heating value of the gas to pipeline quality the system cost is on the order of $2.50-$3.50/MMBtu. Typical returns on investment for projects under construction or planned generally fall into the range of 25-35 percent per year.

Legal Requirements

Criteria established under the Resource Conservation and Recovery Act (RCRA) of 1976 include a requirement that methane concentrations at the landfill boundary not exceed the lower explosive limit of five percent (10 percent landfill gas). This criterion makes a gas control system mandatory at many landfills.

A number of options for gas control are fairly well established. Choice of the proper method can only be made after a careful analysis of site conditions, adjacent land uses and other considerations. One option which is finding increased favor is combining both migration control and gas recovery. This alternative provides protection from the negative effects of methane migration; at the same time, it promotes the use of an otherwise wasted energy resource.

If all or a portion of the installed cost of a gas collection system can be written off as required for migration control, the economic attractiveness of gas recovery will be enhanced.

At a time when consumption of imported oil has associated with it increasingly severe negative effects on the United States' economy, new energy technologies that have the capability of reducing those imports carry an importance transcending traditional economic considerations. Landfill gas is just such a new energy technology.

Although imported crude oil currently (mid-1981) is costing $30-$35 per barrel, it is generally agreed that the cumulative cost to the U.S. economy, including secondary effects such as employment, is two or three times the basic cost. Liquified natural gas currently costs more than $5 per MMBtu wholesale. it is in the light of these considerations, and not merely comparing landfill methane costs with regulated natural gas costs, that landfill methane utilization technology must be judged.

In addition to the increasingly valuable energy, landfill methane utilization brings three important environmental benefits. First, gas migration into areas next to the landfill site is reduced or eliminated, thereby significantly lowering the probability that a hazardous condition will be created. Second, since the gas is being withdrawn from the landfill, residents are not bothered by the smell of gas. Third, the quality of vegetation growing on the landfill is improved, since the gas underneath is being withdrawn with pipes, rather than flowing up through the roots of grass and plants. This is especially important when the final use of the landfill site is a golf course or a park.

In summary, social and environmental considerations can sometimes be at least as important as traditional economics when evaluating the desirability of implementing landfill methane recovery and utilization. Several systems currently on-line or planned have been "justified" to a significant degree based upon these factors.

"It is now believed that between 1000 and 10,000 landfills in the United States are eligible for profitable gas recovery and utilization."

Recovery Sytems

A landfill gas recovery collection system includes wells and piping used for gathering the gas from these wells and transporting it to the processing location (see **Figure 1**). A typical landfill gas recovery well has a 12 to 36-inch diameter bore hole, often drilled to the bottom of the landfill. Well casings, typically three to six inches in diameter and perforated on the bottom third to two-thirds, are inserted into these bore holes. The well casing is installed on a layer of gravel. Then the hole is backfilled to a level of two to four feet above the perforated portion of the well casing with rock or gravel, followed by an impermeable layer a few feet thick of concrete, bentonite, and/or clay. The remainder of the hole is typically backfilled with soil.

The layout of the wells and gathering system depends on a number of factors including results of a field testing program, end use of the landfill surface, and the purpose of the collection system. Testing at a landfill will indicate which areas might provide the most gas of good quality for a gas recovery system.

The raw landfill gas is withdrawn from the wells using pumps connected to the collection manifold. The gas is transported to the processing location. The degree of processing necessary depends on how the gas is to be used. Any landfill gas recovery system should include one or a combination of dehydration processes.

A number of methods can be used to remove the water vapor from the extracted landfill gas. The most common dehydration processes include absorption, adsorption and condensation. Six of the landfill projects in commercial operation do not remove carbon dioxide from the gas but use it after dehydration as medium-Btu gas.

"Recently, several major banks and private party groups have indicated a willingness to participate in landfill gas recovery projects."

In certain landfill gas applications, the heating value of the gas must be upgraded by removal of carbon dioxide. Carbon dioxide can be removed by absorption into a liquid, adsorption on a solid, membrane separation, cryogenic separation or chemical conversion to another compound. At four landfill facilities, the gas is being upgraded and injected into utility pipelines. In addition to dehydration and particulate removal, each of these facilities must remove carbon dioxide from the landfill gas.

Potential Gas Users

The intended end use of the landfill gas at a particular landfill site will determine the quality of gas required and the degree of processing necessary. Each landfill gas recovery project may have unique requirements based on agreements between the seller and buyer of the gas. The raw gas extracted from landfills typically has heating values ranging from 450 to 600 Btu/scf and contains methane, carbon dioxide, and traces of other gases; it typically is saturated and contains particulates. The gas can be used directly; however, for any long-term application, cleanup of the gas is required for reduction of corrosion and hazards.

A comparison of available options for use of landfill gas must be done at each site in order to determine the most economic alternative. There are four basic options for the utilization of landfill gas: (1) direct sale of gas to a customer; (2) generation of electric power; (3) injection into an existing natural gas pipeline; and (4) conversion to other chemical forms. These options differ in the effort required to produce the end product and in the capital cost.

Currently there are 10 projects in commercial operation in the U.S. for recovering and utilizing landfill gas for its methane content. These projects use the landfill gas as fuel for boilers, process heat or electricity generation, or the gas is injected into utility gas pipelines.

A listing of these projects is presented in **Table I.** The systems at Palos Verdes, Mountain View, C.I.D. and Operating Industries inject the processed gas into natural gas transmission lines. The gas from Azusa is used as boiler fuel by a fiberglass manufacturer. The Ascon project ships gas to a nearby oil refinery. A steel products manufacturer uses the gas from Cinnaminson to heat ladles used for molten steel. Gas from Sheldon Arleta and Bradley East is used as boiler fuel by an electric generating station. A convention center uses the gas at City of Industry for boiler fuel.

Summary

The past few years have brought about rapid development of the technology. The equipment needed for landfill gas recovery and utilization is available today, and the cost of the energy produced is competitive with other, more conventional sources.

Municipal Solid Waste: A Utility Fuel?

by C.R. McGowin

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Introduction

Rapid increase in both energy and solid waste disposal costs have made resource and energy recovery from municipal solid waste (MSW) a hot topic in communities all over the U.S. In many cases, the electric utility is being called upon to participate as a customer for the recovered energy as refuse-derived fuel (RDF), steam or electricity. This paper addresses the alternative roles electric utilities can assume, the MSW-to-electricity conversion efficiencies and costs of several alternative technologies, and preliminary guidelines for cofiring refuse-derived fuel with coal or oil in utility boilers.

Alternative Roles of Electric Utilities

During the past 10 years, electric utilities have assumed several roles in community resource recovery projects, including purchase of refuse-derived fuel, steam, or electricity; cofiring of RDF with coal or oil in a utility boiler; and ownership and operation of dedicated refuse-fired facilities. These alternative roles are shown in Table 1.

The revenues generated by sale of refuse energy to a utility directly offset the costs of financing and operating the resource recovery facility and thus directly affect the overall economics. If a utility buys RDF for cofiring, the contract price is usually tied to the price of the fuel being replaced, adjusted for the cost of financing and operating the RDF firing facilities. When used as a replacement fuel for coal, RDF is purchased by the utility at a relatively low price, which can even be negative, i.e., the fuel supplier must pay the utility to burn RDF. If RDF is replacing high-cost fuel oil, the RDF price will be correspondingly higher.

Purchase of electricity from refuse-fired cogeneration facilities is now regulated by the Public Utilities Regulatory Policy Act (PURPA), and public utilities are required to purchase electricity at their "avoided" generation cost, i.e., the generation cost for less efficient units replaced by refuse-fired generation. This arrangement will usually generate the highest revenues from sale of refuse energy, but profits are limited by higher financing costs.

In any case, there is little incentive for a utility to participate in a resource recovery project other than providing a community service. Fuel savings resulting from use of refuse fuel, steam, or electricity are passed on directly to the rate payer and the utility is not compensated for the increased risk, for example, of cofiring RDF.

Utility Experience

Most of the electric utility experience has occurred since 1970 in existing coal- and oil-fired boilers, retrofitted to cofire RDF (Table 2).[1-10] To date, eight utilities have cofired RDF in their boilers, of which three are currently operating (Ames, Iowa; Madison, Wis.; and Rochester, N.Y.). In addition, two new units designed for cofiring coal and RDF are in startup (Ames, Iowa; and Lakeland, Fla.), another new unit is under construction (Columbus, Ohio), and an existing unit is to be retrofitted to burn RDF (Baltimore, Md.). As discussed later, utility experience with RDF has been both good and poor. This suggests that the technical basis does not yet exist to confidently design and operate RDF cofiring systems in existing utility boilers.

Table 1: Alternate Roles of Electric Utilities

Refuse-to-Energy Technology	Alternative Roles of Utility
• Mass burning of MSW in a dedicated waterwall boiler driving a turbine generator.	—Customer for electricity. —Customer for steam. —Operator and/or owner of boiler and turbine generator.
• Preparation of RDF for semi-suspension firing in a dedicated boiler driving a turbine generator.	—Customer for electricity. —Customer for steam. —Customer for RDF and owner/operator of boiler and turbine/generator.
• Cofiring of RDF with coal or oil in utility boiler.	—Customer for RDF. —Operator of utility boiler fired by RDF and coal or oil.
• Generation of gas by landfill gas recovery.	—Customer for gas for use as boiler fuel or pipeline gas.

Table 2: Experience with RDF Cofiring in Large Utility Boilers

Location	Utility	Unit	MW	Primary Fuels	Date of Startup	Status/ Comment
Tangentially-Fired Boilers						
St. Louis, MO	Union Electric Co.	Meramec 1	140	Coal	1972	Shutdown 1976
Ames, IA	Ames Municipal Electric System	Ames 7	35	Coal	1975, 1978	Operational with dump grate
Milwaukee, WI	Wisconsin Electric Power Co.	Oak Creek 7, 8	310 each	Coal	1977	Shutdown September 1980
Chicago, IL	Commonwealth Edison Co.	Crawford 7 + 8	208/325	Coal		Shutdown 1979
Rochester, NY	Rochester Gas and Electric Corp.	Russell 1, 2, 3, 4	42/62/62/75	Coal	1981	Unit 3 operational with dump grate
Cyclone-Fired Boilers						
Bridgeport, CT	United Illuminating Co.	Bridgeport Harbor 1	86	No. 6 0il	1980	ECO-FUEL II, plant shutdown October 1980
Baltimore, MD	Baltimore Gas and Electric Co.	Crane	200	Coal	1980	Tested in 1980, conversion planned
Wall-Fired Boilers						
Madison, WI	Madison Gas and Electric Co.	Blount Street 1&2	50 each	Coal	1979	Operational with dump grate
Lakeland, FL	City of Lakeland	McIntosh 3	364	Coal	1981	New unit in startup with dump grate
Ames, IA	Ames Municipal Electric System	Ames	65	Coal	1981	New unit in startup with dump grate
Stoker-Fired Boilers						
Ames, IA	Ames Municipal Electric System	Ames	7.5, 12.5	Coal	1975	Operational, not currently burning RDF
Columbus, OH	City of Columbus	Columbus	90	Coal	1983	Under construction for 1983 operation

More recently, dedicated MSW and RDF-fired boilers are being planned, built and operated in the U.S., and several of these projects include sale of steam or electricity to electric utilities. Dedicated mass burning, MSW-fired boilers are operating at Braintree and Saugus, Mass.; Harrisburg, Pa.; Chicago, Ill.; Nashville, Tenn.; Norfolk, Va.; and Waukesha, Wis. Dedicated RDF-fired boilers have been built in Niagara Falls and Hempstead, N.Y.; Akron, Ohio; and Miami, Florida.

Comparison of Refuse-to-Electricity Technologies

For purpose of discussion, it is useful to compare the energy recovery efficiencies and costs of the alternate technologies using a model of a municipal-utility resource recovery project. The comparison is derived from a recently-completed assessment of refuse-to-electricity technologies, cosponsored by EPRI and the New York State Energy Research and Development Authority.[1]

As shown in Figure 1, three systems are evaluated:

- Mass burning of MSW in a dedicated boiler driving a separate turbine generator.
- Preparation of coarse RDF and firing in a dedicated boiler driving a separate turbine-generator.
- Preparation of fluff RDF and cofiring with coal in an existing utility boiler for two levels of RDF preparation (RDF A and B).

The RDF preparation flowsheets; predicted RDF properties and yields; boiler, steam-cycle, and overall MSW-to-electricity conversion efficiencies; and costs for the alternative technologies are compared in the following sections.

RDF Preparation and Predicted Properties

The degree of refuse processing varies between none for mass burning of MSW to considerable for fluff RDF cofiring (Figure 2). As more processing is applied, RDF quality improves as indicated by the ash and Btu contents, but Btu yield in the product RDF decreases significantly (Table 3). For example,

Figure 1: Comparison of Refuse-to-Electricity Technologies

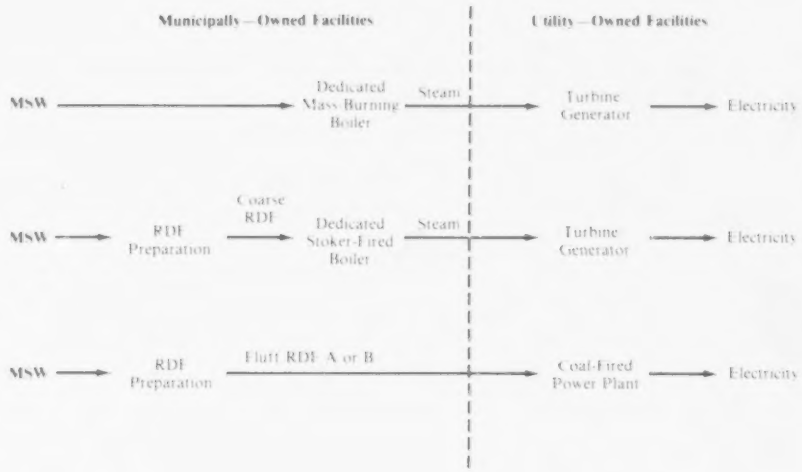
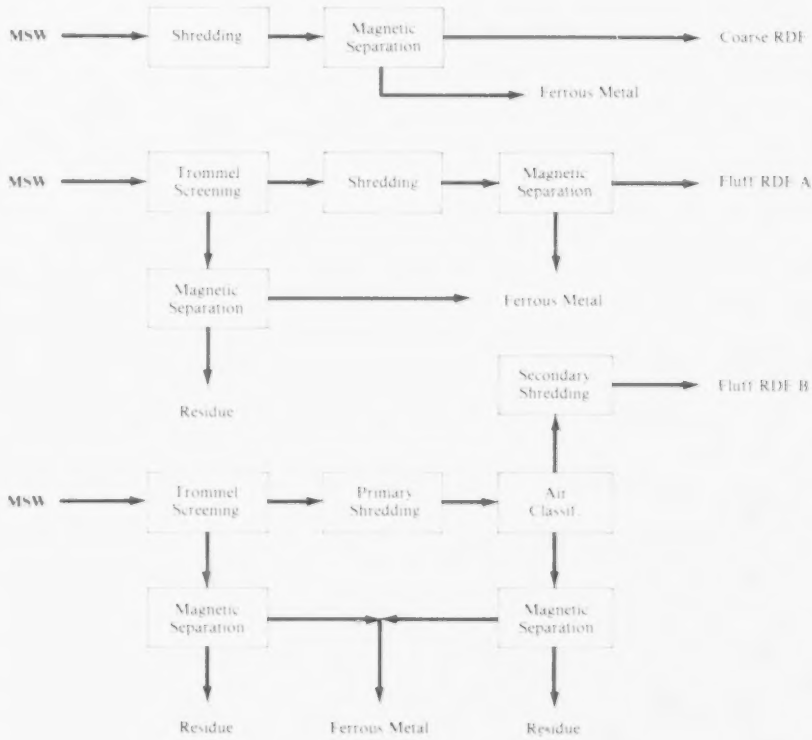


Figure 2: Refuse Processing Flow Sheets



coarse RDF is prepared by shredding and magnetic separation, which reduces the predicted ash content from 25 percent for MSW to 21 percent at 98.8 percent Btu recovery. By comparison, pretrommelling, shredding, and magnetic separation produces fluff RDF A, containing about 9 percent ash but decreases the Btu yield to 84.6 percent. Fluff RDF B is produced in the same way as RDF A, except as air classified between the primary and secondary shredders and only the residues are passed through magnetic separation. As shown in Table 3, the air classifier only reduces the predicted ash content from 8.9 to 7.8 percent with a significant further reduction of Btu recovery (to 67 percent).

This analysis suggests that an air classifier may not be required to produce a low ash RDF in a process incorporating trommel screens ahead of the primary shredder. However, such a process has not been built and little data are available to confirm these results.

Overall MSW to Electricity Conversion Efficiency

The overall MSW-to-electricity conversion efficiency is estimated by multiplying together the RDF Btu yield (Table 3), boiler efficiency (Table 4), steam-cycle efficiency (Table 5), and adjusting for auxiliary power consumption, as shown in Table 6. The overall efficiencies vary between 18 and 24 percent. The lower efficiency for MSW mass burning (18.8 percent) results primarily from the low boiler efficiency (61.7 percent), which in turn is caused by low combustion efficiency, high excess air, and high boiler exit gas temperature. RDF B cofiring (18.0 percent overall efficiency) operates at higher boiler and steam cycle efficiencies (75.4 and 43.1 percent), but is penalized by a low RDF Btu yield (66.6 percent). Cofiring of RDF A has the best overall efficiency (23.8 percent) due to its higher Btu yield (84.6 percent).

Economic Comparison

The economic viability of a resource recovery project can be measured by the breakeven tipping fee, which is charged for refuse disposal. The tipping fee is set to make up the difference between the

Table 3: Comparison of Refuse Fuel Properties and Yields

Refuse Fuel Type:	MSW	Coarse RDF	Fluff RDF A	Fluff RDF B
Fuel Preparation:	None	Shredding, Magnetic Separation	Trommelling, Shredding, Magnetic Separation	Trommelling, Shredding, Air Classification, Magnetic Separation
RDF Properties:				
% Moisture	25.2	26.4	25.2	25.2
% Ash	24.8	21.1	8.9	7.8
Btu/lb	4450	4677	5693	5841
Particle Size:	—	95% < 6 in.	90% < 3/4 in.	90% < 3/4 in.
RDF Yields:				
% Mass Yield	100.0	94.0	66.2	50.8
% Btu Yield	100.0	98.8	84.6	66.6

Table 4: Boiler Efficiencies for Refuse Firing

Refuse Firing Mode:	100% Refuse Firing in Dedicated Boiler		Coal/RDF Cofiring in Utility Boiler	
Refuse Fuel Type:	MSW	Coarse RDF	Fluff RDF A	Fluff RDF B
Boiler Operating Conditions:				
Excess Air (%)	100	40	40	40
Exit Gas Temperature (°F)	500	350	350	350
Combustion Efficiency (%)	95.5	98	98[a]	98[a]
Boiler Efficiency (%)	61.7	73.5	75.4[a]	75.4[a]

a) Applies to RDF conversion to steam only.

Table 5: Steam Cycle Thermal Efficiencies

Refuse Firing Mode:	100% Refuse Firing in Dedicated Boiler		Coal/RDF Cofiring in Utility Boiler	
Refuse Fuel Type:	MSW	Coarse RDF	Fluff RDF A	Fluff RDF B
Steam Conditions:				
Pressure (psi)	850	850	2400	2400
Temperature (°F)	900	900	1000	1000
Reheat Temp. (°F)	—	--	1000	1000
Gross Steam Cycle Efficiency:				
Btu/kWh	9681	9703	7914	7914
%	35.2	35.2	43.1	43.1

Table 6: Overall MSW to Electricity Conversion Efficiencies

Refuse Firing Mode:	100% Refuse Firing in Dedicated Boiler		Coal/RDF Cofiring in Utility Boiler	
Refuse Fuel Type:	MSW	Coarse RDF	Fluff RDF A	Fluff RDF B
RDF Btu Yield (%):	100.0	98.8	84.6	66.6
Boiler Efficiency (%):	61.7	73.5	75.4[a]	75.4[a]
Gross Steam Cycle Efficiency (%):	35.2	35.2	43.1	43.1
Auxiliary Power as % of Gross Output:				
Refuse Handling[b]	13.8	11.4	5.8[a]	9.3[a]
Coal-Fired Plant	—	—	7.4	7.4
Overall MSW to Electricity Conversion Efficiency:				
%	18.8	22.6	23.8	18.0
Btu/kWh	18,190	15,080	14,340	18,930

[a] Applies to RDF contribution to steam and electricity only.

[b] Auxiliary power consumed by MSW and RDF processing, handling and firing.

cost of financing and operating the resource and energy recovery facility and the revenues generated by sale of recovered energy and byproducts. Because the tipping fee is calculated by difference, it can be quite sensitive to key parameters, including:

- price paid for refuse energy;
- byproduct credits;
- overall MSW-to-refuse energy conversion efficiency;
- capital and operating costs of facilities;
- MSW capacity;
- economic assumptions; and
- other site-specific factors.

For purposes of illustration, the costs of the four MSW-to-electricity technologies are compared using the municipal-utility model. The municipality owns and operates the resource recovery and dedicated boiler facilities, and the utility owns and operates the RDF cofiring boiler and turbine generator facilities.

Table 7: Operating and Cost Data for MSW-to-Electricity Technologies

Basis: End-of-1980 dollars

MSW to Electricity Technology	MSW Mass Burning	Coarse RDF Firing	RDF A Cofiring	RDF B Cofiring
Municipal Facilities	Dedicated Boiler	RDF Preparation Dedicated Boiler	RDF Preparation	RDF Preparation
MSW Capacity (ton/yr)	260,000	260,000	260,000	260,000
Total Capital (10^6)	68	74	36	38
Fixed O&M (10^6/yr)	3.2	4.6	2.8	2.8
Variable O&M (10^6/yr)	1.9	1.7	1.5	1.9
Utility Facilities	Turbine/ Generator	Turbine/ Generator	Coal or Oil-Fired Boiler and Turbine/Generator	
Generating Capacity (MW)	16.9	19.8	500	500
Capacity Factor (%)	95	95	40	40
Generation (10^6kWh/yr)	141	165	1752	1752
Total Capital (10^6)	7.7	8.9	4.8	4.8
Fixed O&M (10^6/yr)	0.8	0.8	0.5	0.5
Variable O&M (10^6/yr)			6.3	6.3
Reference Utility Power Plant			**Coal-Fired**	**Coal-Fired**
Generating Capacity (MW)			500	500
Capacity Factor (%)			40	40
Net Heat Rate (Btu/kWh)			9800	9400
Variable O&M (mills/kWh)			3.5	1.5

Other major assumptions include:

- 260,000 tons/year annual MSW processed;
- no credits for recovered metal and glass;
- EPRI economic assumptions;[12]
  (8.5% inflation)
  (12.5% utility cost of capital)
- 9.75% municipal cost of capital;
- 20-year project life; and
- costs in end-of-1980 dollars.

The operating and cost data for the four systems and the reference coal and oil-fired plants are shown in Table 7.

The revenues generated by sale of RDF, steam, or electricity are important because they offset the tipping fee directly on a one-for-one basis. The energy revenues are, in turn, strongly dependent on the MSW-to-energy conversion efficiency, i.e., the amount of energy transferred and the price paid for the energy. As discussed previously, the energy price is derived from either the variable O and M and fuel cost savings resulting from use of refuse energy in the reference coal or oil-fired power plant or the utility's "avoided" cost under PURPA.

The estimated breakeven tipping fees are compared for the four technologies as functions of the coal or fuel oil cost and the PURPA avoided cost in Figures 3 and 4. Figure 3 shows that RDF A cofiring with coal or oil yields the lowest breakeven tipping over the full range of reference fuel costs. Reasons include the relatively high overall refuse-to-energy conversion efficiency and the low capital and operating costs of this system. At a delivered coal cost of 1.70 $/10^6$ Btu, the estimated breakeven tipping fee is 33.50 $/ton MSW, while at a fuel oil cost of 5.15 $/10^6$Btu, the tipping fee is 23.75 $/ton. Thus, substitution of RDF for fuel oil will usually result in lower tipping fees. The highest tipping fee is exhibited by coarse RDF preparation and firing in a dedicated boiler, which is attributed to the high capital cost of the RDF preparation and firing facilities.

Figure 4 shows the sensitivity of the breakeven tipping fee to the PURPA avoided cost paid by the utility for electricity generated by dedicated MSW and coarse RDF-fired facilities. The lowest tipping fee is achieved by MSW mass burning (39.15 $/ton MSW at 50 mills/kWh), due to the lower capital investment required.

The breakeven tipping fees presented in Figures 3 and 4 are generally higher than other published estimates for a number of reasons. These include the assumption of zero byproduct credits for recovered metal and glass, the relatively low utility payments for RDF and steam, and redundancy in key equipment, including resource recovery process trains and dedicated boilers.

This evaluation suggests that the most cost-effective way of recovering energy from refuse is to prepare a low-ash RDF with minimal processing and maximum Btu recovery and cofire the RDF with coal or oil in a utility boiler. However, the economics are penalized by the relatively low price paid for the energy, which is in turn constrained by the costs of operating and financing the refuse-handling facilities at the power plant.

Another uncertainty of this approach is the long term capability of the utility to burn RDF while operating under economic dispatch, i.e., always operating the least cost generating unit. In later years of a project, a utility might have to operate a unit at a higher capacity factor than allocated by economic dispatch in order to accommodate refuse burning. This results in an economic dispatch penalty, charged back against utility energy payments, which would increase the tipping fee.

RDF Cofiring Guidelines

Focusing on RDF cofiring during the last 10 years, a variety of problems has been encountered in large utility boilers cofiring RDF with coal or oil. As shown in Table 8, these problems include unburned heavy RDF particles in the bottom ash, formation of deposits on boiler tubes, overloading of the ash handling system, boiler derating due to increased gas flow and particulate loading, and decreased electrostatic precipitator performance.[1-10] Solutions to several of the problems have been tested in utility boilers as shown in Table 8, and the experience provides the basis for the preliminary RDF cofiring guidelines discussed later.[1-8]

Figure 3: Sensitivity of Breakeven Tipping Fee to Coal and Oil Cost

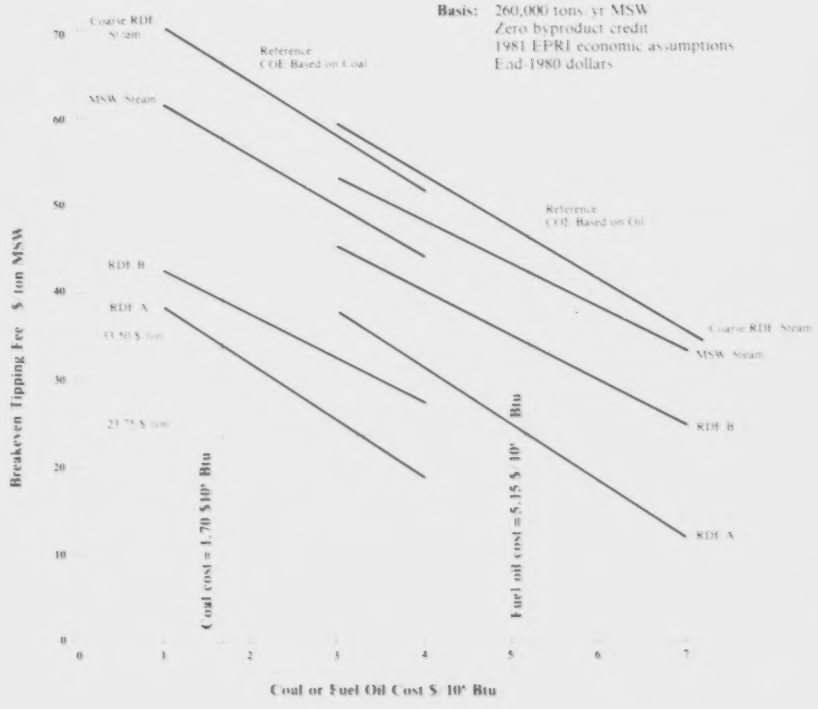
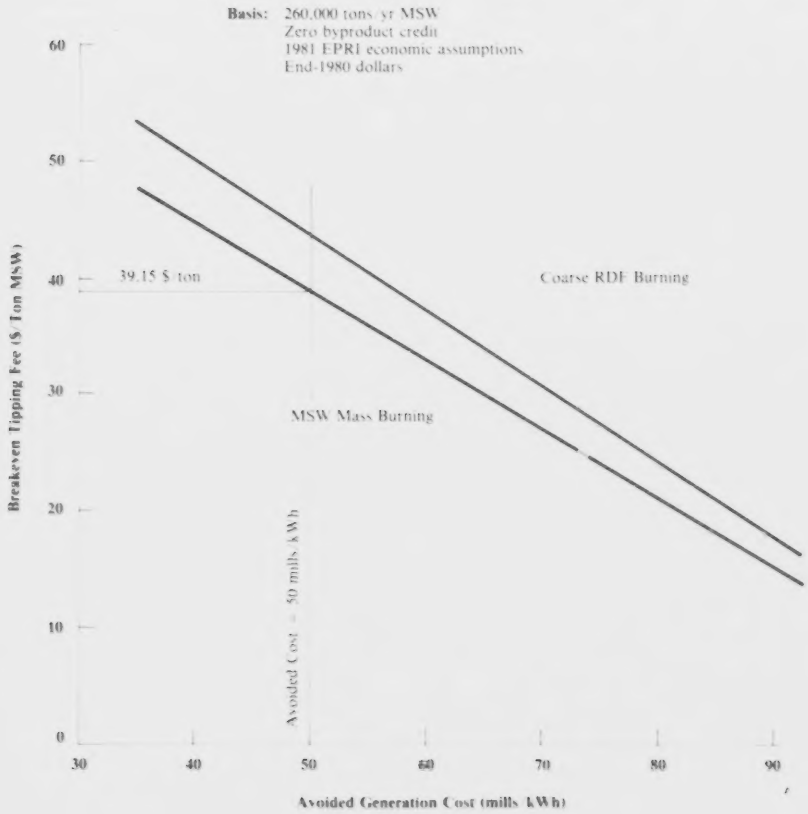


Table 8: Problems Encountered with RDF Cofiring in Utility Boilers

Problem	Solution
• Dropout of unburned material in bottom ash.	—Install dump grate at bottom of boiler.
• Overload bottom ash hauling system.	—Reduce ash content of RDF.
• Formation of deposits on boiler sidewalls and convective tube surfaces.	—Reduce glass, metal and ash contents of RDF —Avoid high-heat release rate boilers with inherent slagging and fouling problems.
• Reduced boiler efficiency and generating capability.	—Reduce ash and moisture contents of RDF.
• Reduced electrostatic precipitator performance.	—None.

Figure 4: Sensitivity of Breakeven Tipping Fee To Avoided Generation Cost under PURPA



Unburned material in the bottom ash consist of wood, plastic and other dense particles which do not burn during the one or two seconds residence time in the furnace. The problem has been eased by installation of dump grates in the bottom of the boiler. The grates remain closed most of the time to retain and burn combustible particles and are periodically opened to allow the ash to fall into the ash pit. The first installation of dump grates was in the tangentially-fired Unit 7 at Ames, Iowa.[1,2] Dump grates have also been installed in operating units in Madison, Wis., and Rochester, N.Y., and in new units in Lakeland, Fla., and Ames, Iowa.[5,7,8]

Bottom ash handling and boiler slagging and fouling problems have generally occurred in units burning RDF with high ash content and in boilers with high heat release rates that exhibit such problems while burning coal only (e.g., Milwaukee). In contrast, the experience has been generally satisfactory at other locations where slagging and fouling is not a problem when burning coal and where the RDF has been processed to reduce the ash content to a low level. For example, installation of disc screens at the Ames resource recovery plant in 1979 significantly improved RDF quality and eliminated formation of boiler deposits which had been a problem.[1] Similarly, few problems have been observed at Madison, Wis., where the RDF preparation process uses a trommel screen ahead of the shredder to reduce ash content. Reduced ash content should also reduce the boiler derating required, because particulate loading and thus the potential for tube erosion are reduced.

Limited RDF cofiring experience in cyclone-fired boilers at Bridgeport, Conn., and Baltimore, Md., suggests that these units may be more amenable to RDF cofiring than other boiler types.[9] For example, dry dust RDF was cofired with fuel oil at Bridgeport at rates in excess of 30 percent heat input with satisfactory impact on furnace slag tap operation and other operating parameters.

Based on utility experience to date, it is possible to state preliminary design and operating guidelines for RDF cofiring in utility boilers.

- suspension-fired boilers:
  —install bottom dump grate;
  —minimize RDF ash, glass and metal content of RDF via use of pretrommel screen in the preparation process; and
  —avoid tightly designed boilers that already exhibit fouling and slagging with coal.
- cyclone-fired boilers:
  —these units are less sensitive to RDF quality than suspension-fired units; and
  —no bottom dump grate is required or possible.

EPRI/Argonne National Laboratory Project

Preparation of detailed guidelines for cofiring RDF in utilities will be the subject of a project to be cosponsored by EPRI and Argonne National Laboratory during 1982 and 1983. The scope of the project will include:

- review utility experience with RDF cofiring;
- develop RDF specifications and recommend flowsheets for RDF preparation; and
- develop design and operating guidelines for RDF handling, storage and firing in utility boilers.

The guidelines wil be adapted for different combinations of boiler and primary fuel types, e.g., wall-fired, cyclone and tangential boilers fired by coal and fuel oil.

Conclusions

1. *Municipal solid waste has a relatively low value as a supplemental fuel in utility boilers due to the need to charge capital and operating costs for refuse handling facilities against coal or fuel oil savings and the potential for an economic dispatch penalty. The value of refuse energy is highest in cases where a utility is buying electricity at its avoided generation costs under PURPA.*

2. *Refuse-to-energy systems should be as simple as possible and maximize the energy transferred to the energy customer.*

3. *The RDF preparation process should be designed to maximize Btu recovery, produce a low-ash RDF and be simplified as much as possible to reduce capital and operating costs.*

4. *The lowest breakeven tipping fee was estimated for cofiring RDF, prepared via pretrommelling, shredding and magnetic separation with coal or oil in a utility boiler. The predicted low-ash content of RDF prepared in this way suggests that air classification may not be necessary. This approach should be tested by the resource recovery industry soon.*

5. *The highest overall energy recovery efficiency is achieved by coarse RDF preparation and firing in a dedicated boiler and by cofiring pretrommelled RDF in a utility boiler.*

6. *Preliminary guidelines for RDF cofiring were derived based on utility experience to date. They include use of bottom dump grates in suspension-fired boilers, preparation of a low-ash RDF via use of trommel screens ahead of the shredder, and avoiding boilers with chronic slagging and fouling problems.* ∞

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